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(54) Method and apparatus for borehole fluid influx detection

(57) The infusion of fluid from the formation being drilled into a borehole (30) is detected by modulating the drilling fluid stream in the drill pipe and detecting pressure variations commensurate with the modulation at the surface in the annulus (28) between the drill pipe (12) and wall of the well. The detected pressure variations are compared in phase and/or amplitude with their own near term past history or with the drilling fluid pressure variations in the drill pipe (12) resulting from the modulation. Variations in phase or amplitude which can not be attributed to changes in the drilling operation will be indicative of fluid infusion.

Fig. 1

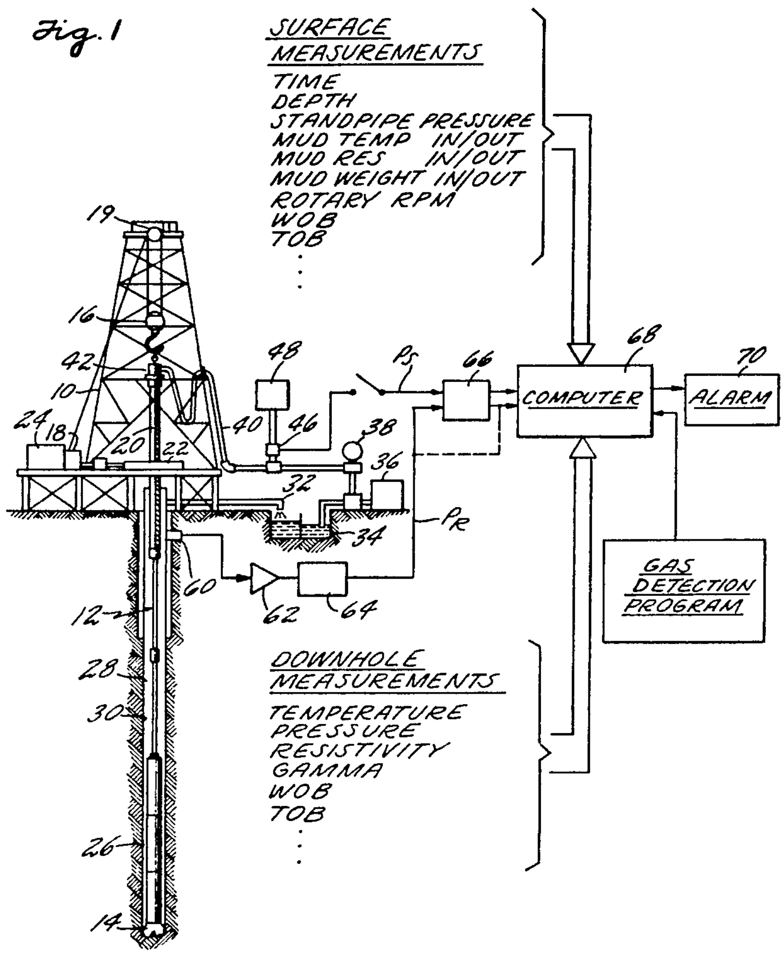

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Fig. 1

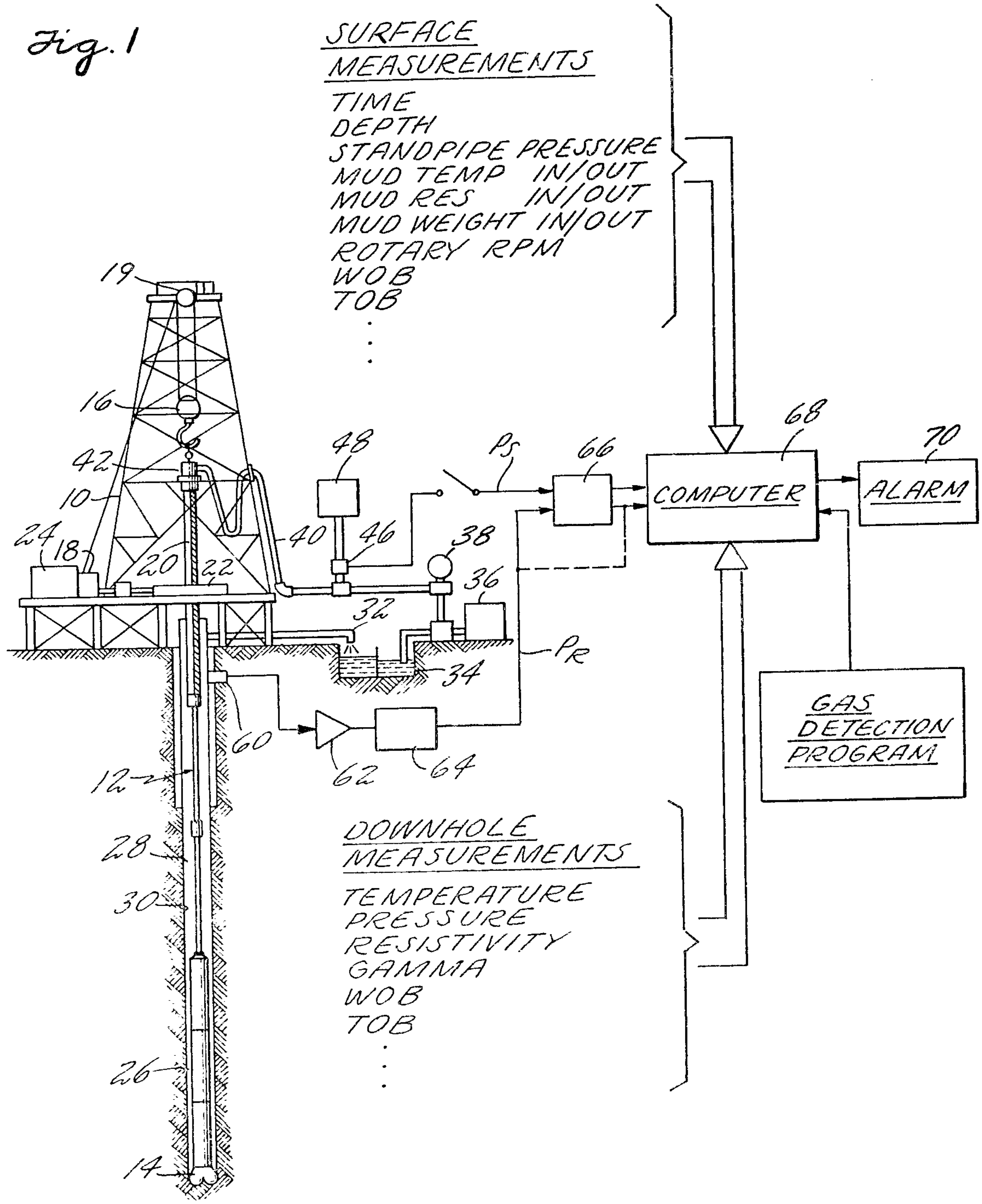

SURFACE MEASUREMENTS
TIME
DEPTH
STANDPIPE PRESSURE
MUD TEMP IN/OUT
MUD RES IN/OUT
MUD WEIGHT IN/OUT
ROTARY RPM
WOB
TOB
COMPUTER
ALARM
GAS DETECTION PROGRAM
DOWNHOLE MEASUREMENTS
TEMPERATURE
PRESSURE
RESISTIVITY
GAMMA
WOB
TOB
19
16
42
10
24
18
20
22
40
48
46
38
36
32
34
P_S
66
68
70
P_R
60
62
64
12
28
30
26
14

Fig. 2

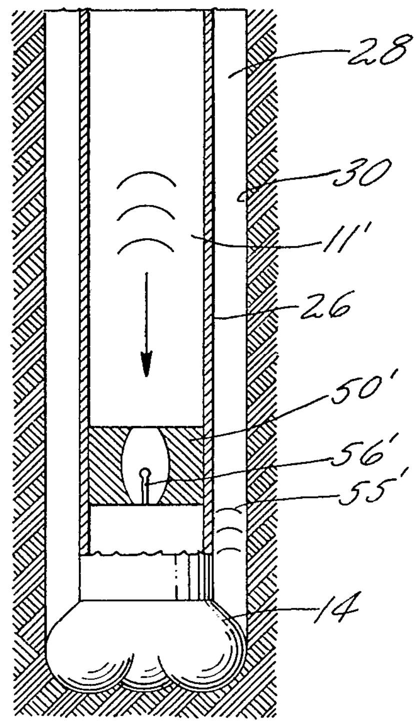


Fig. 5

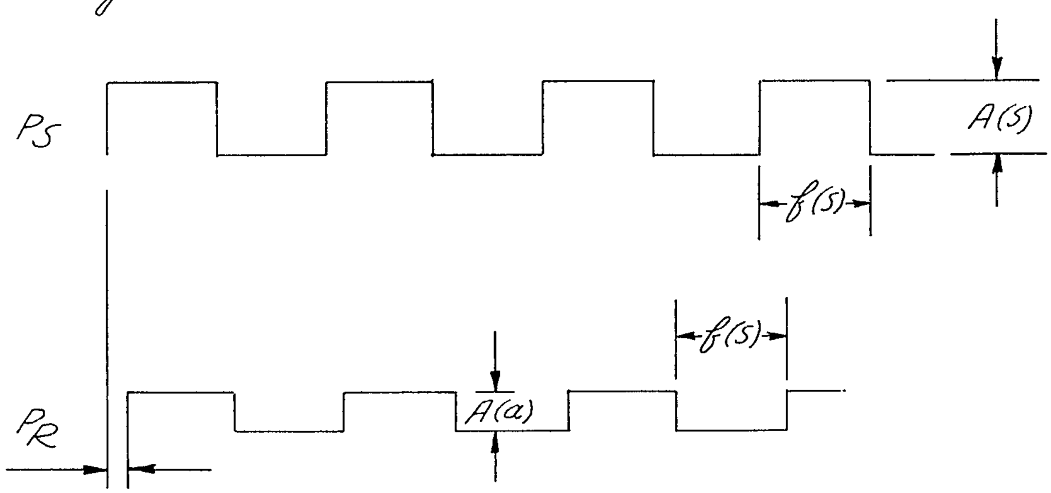
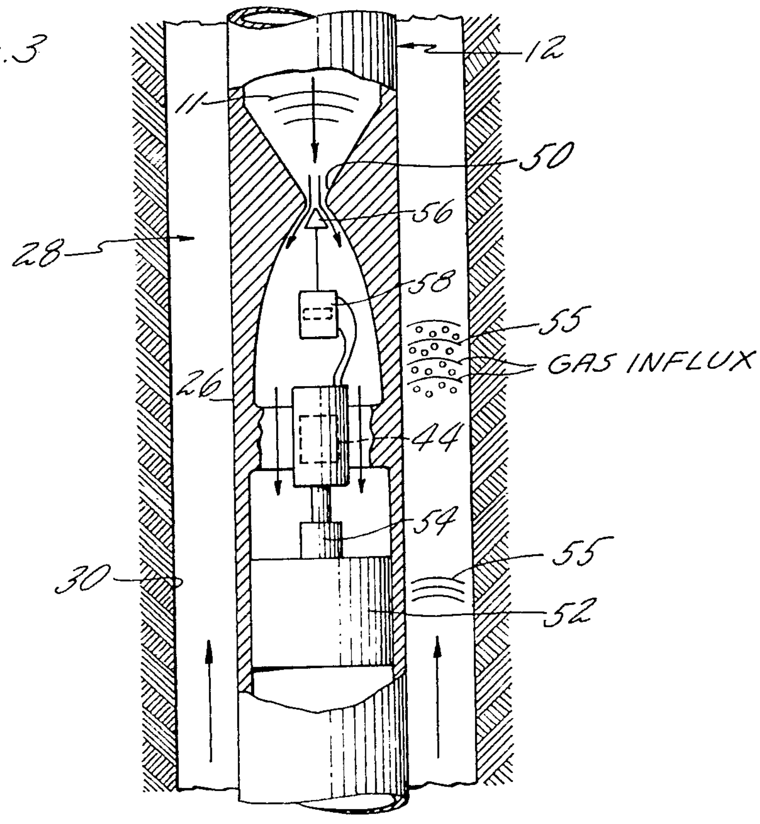


Fig. 3



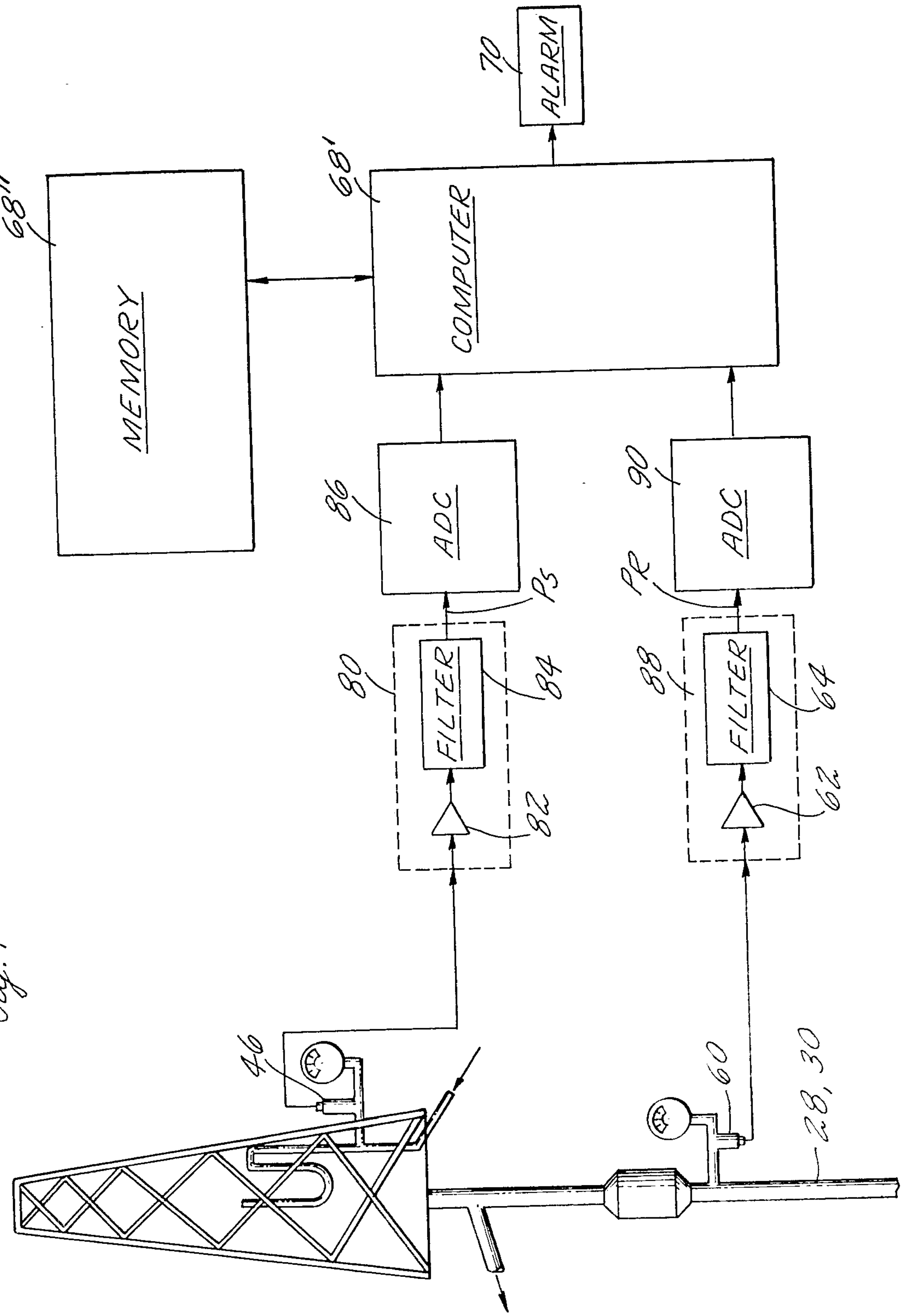

MEMORY
68''
COMPUTER
68'
ALARM
70
ADC
86
ADC
90
FILTER
84
80
82
FILTER
64
88
62
PS
PR
46
60
28, 30

Fig. 4

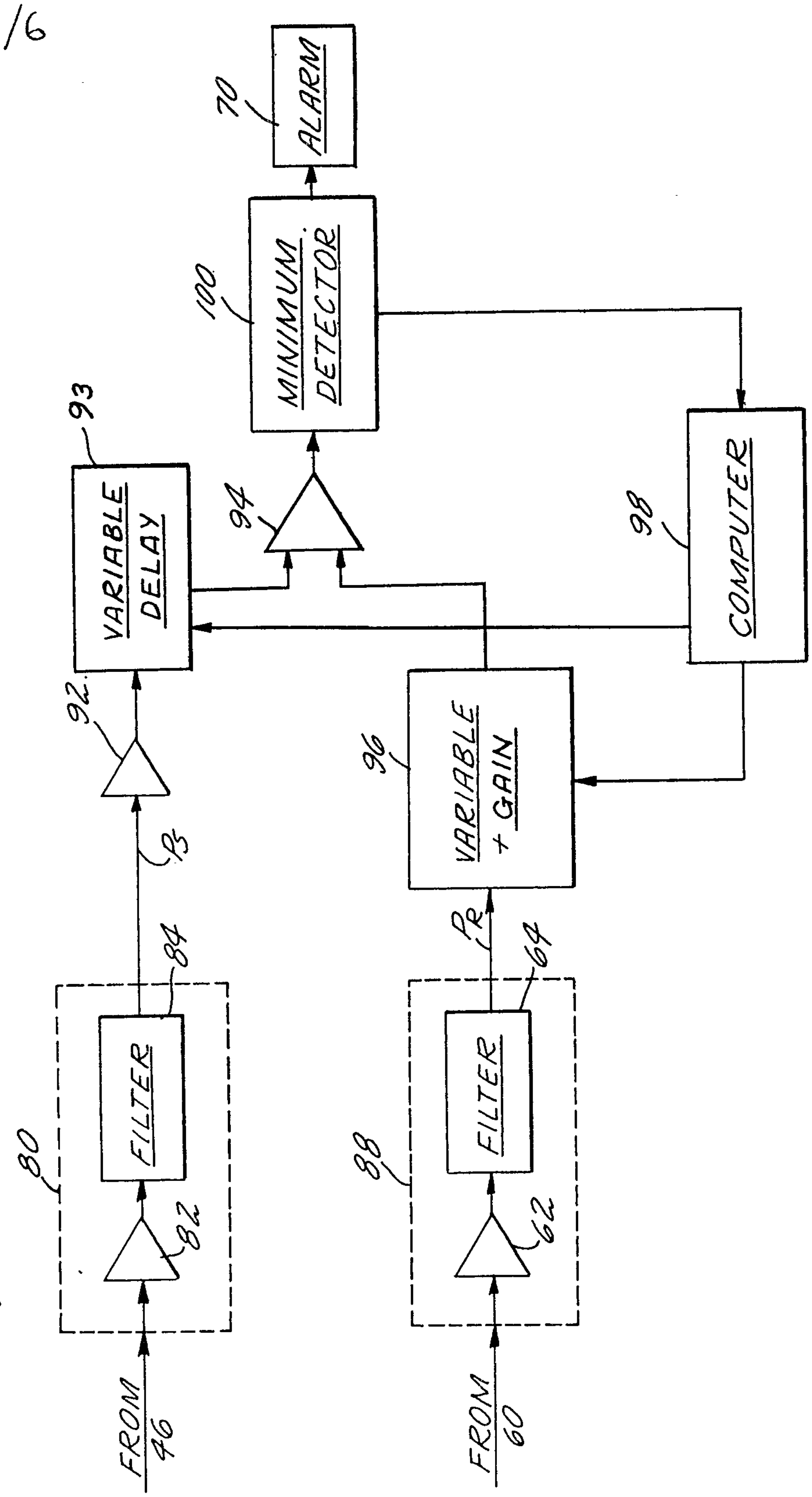
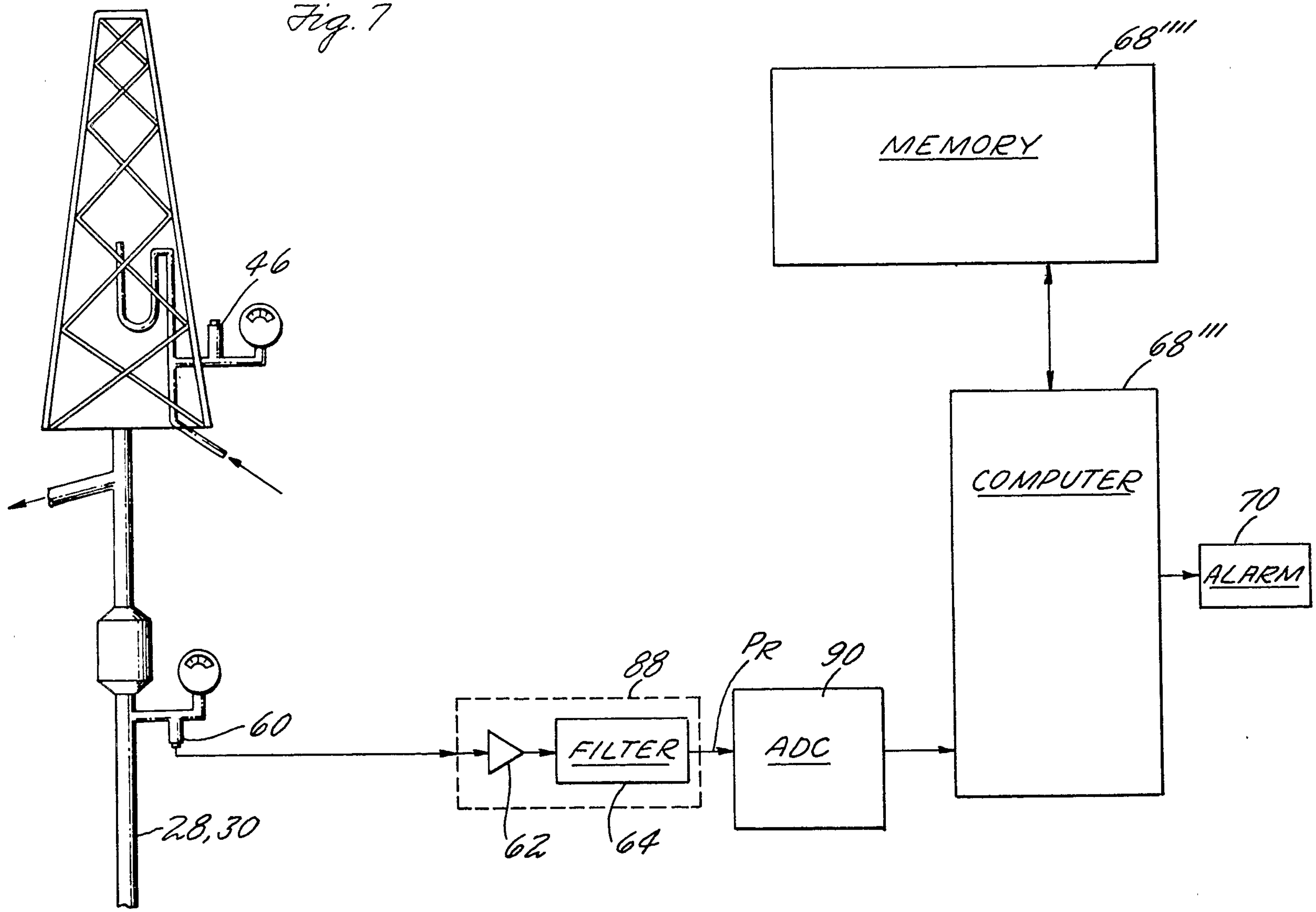

ALARM
70
MINIMUM DETECTOR
100
VARIABLE DELAY
93
94
COMPUTER
98
92
VARIABLE + GAIN
96
FILTER
84
80
82
FILTER
64
88
62
FROM 46
FROM 60

Fig. 6

Fig. 7



46
60
28,30
88
62
64
FILTER
PR
90
ADC
MEMORY
68''''
68'''
COMPUTER
70
ALARM

SPECIFICATION

Method and apparatus for borehole fluid influx detection

The present invention relates to exploration for sources of hydrocarbon fuel and particularly to enhancing the safety of oil and gas well drilling procedures. More specifically, this invention is directed to apparatus and methods for detection of the infusion of fluid into a borehole and especially to apparatus and methods for a fluid infusion detection system which is continuously operable during drilling for blowout protection.

In the drilling of oil and gas wells, drilling safety and efficiency are paramount considerations. Efficient operation of the drilling apparatus, particularly as wells are drilled deeper and offshore activity increases, demands that data of interest to the driller be collected downhole and be sensed and transferred to the surface "continuously", i.e. without the lengthy delays which would be incident to stopping drilling and lowering test instruments down the borehole. In recent years, significant advances have been made in measurement-while-drilling (MWD) technology. For examples of MWD systems for use in the measurement of borehole directional parameters, reference may be had to U.S. Patents 3.982.431, 4.013.945 and 4.021.774.

The measurement systems of the above-referenced patents utilize mud pulse telemetry to transmit information from the vicinity of the drill bit to the surface drilling platform. Mud pulse telemetry consists of the transmission of information via a flowing column of drilling fluid, i.e. mud, the information commensurate with the sensed downhole parameters being converted into a binary code of pressure pulses in the drilling fluid within the drill pipe which are sensed at the surface. These pressure pulses are produced by periodically modulating the flowing mud column at a point downhole by mechanical means, and the resulting periodic pressure pulses appearing at the surface end of the mud column are detected by a pressure transducer conveniently located in the standpipe. The drilling mud is pumped downwardly through the drill pipe (string) and thence back to the surface through the annulus between the drill string and wall of the well for the purpose of cooling the bit, removing cuttings produced by the operation of the drill bit from the vicinity of the bit and containing the geopressure.

As noted above, drilling safety is of paramount importance, and one safety problem relates to what is known as a "blowout". A zone of high geopressure, contained by cap rock, will occasionally be unknowingly encountered during drilling. If this pressure exceeds the hydrostatic pressure exerted by the drilling mud, and the formation has sufficient permeability to allow fluid flow, then the formation fluid will displace the drilling mud. This is referred to as a "kick"; and if unchecked will cause what is known as a "blowout" condition. One borehole condition which the driller desires to monitor, in order to ensure against "blowout", is gas influx.

While various techniques have previously been proposed, and in some cases implemented, for measuring gas infusion into a borehole, the previously proposed techniques have not been suited for MWD and have often been either complex, difficult to implement or have been comparatively slow. The prior gas influx measuring techniques have also often been incapable of providing unambiguous information thus requiring repeated tests and/or the use of plural measuring techniques. The methods of measuring gas influx into a borehole proposed in the prior art have included sensing the borehole annulus pressure, sensing the pressure differential between the interior of the drill string and the annulus, measuring the velocity of sound in the drilling mud, measuring the resistivity of the drilling mud and various other tests based upon attempts to measure the pressure of the formation through which the drill string is penetrating or has penetrated. As noted above, these previously proposed gas detection techniques, and particularly those based upon pressure measurements, all have deficiencies which precluded their used in MWD and otherwise severely limited their usefulness.

In accordance with the present invention, there is provided an apparatus for detection of fluid influx in a borehole in which a drill string is positioned, the drill string cooperating with the wall of the borehole to define an annulus, and in which drilling fluid is circulated from the surface through the interior of the drill string and into the annulus back to the surface, the apparatus for detection of fluid influx including means for generating a coherent energy signal at a downhole location and propogating said signal as a primary signal in the drilling fluid in said drill string and as a secondary signal in the drilling fluid in said annulus, and means for detecting at least said secondary signal, and means for employing said detected signal in a comparison to determine fluid influx into the annulus.

Frequency or amplitude modulation of the mud flow in the standpipe by a coherent energy source at a point near the drill bit will result in the mud flow in the annulus containing information in the form of reflections of the modulation of the flow in the standpipe. Pressure monitoring of the mud flow in the annulus at the surface thus results in the detection of the reflected information resulting from modulation of the column of drilling mud in the drill string (standpipe). In one embodiment of the invention, the pressure variations detected in the annulus are compared to pressure variations detected in the standpipe. A significant change in phase

and/or amplitude ratio between the standpipe and annulus pressure variations, particularly a change in phase and/or amplitude ratio which constitutes a significant deviation from a previously established history, will indicate that there is a fluid influx into the annulus since fluid, for example gas, flowing into the drilling mud will produce attenuation of the modulated information and/or will affect the transmission velocity. In accordance with a second embodiment of the invention, the pressure variations in the drilling mud flowing up the annulus are compared with near past history of such annulus pressure variations and, after appropriate compensation for any changes which have been made in the drilling operation, the results of the comparison are used for fluid influx detection. When the annulus signal is lost or severely altered in either amplitude or arrival time or both, an alarm may be instituted indicating that fluid has entered the borehole. The signal generator means will produce pressure pulses, particularly pulses in the sub sonic or sonic frequency range. Apparatus of preferred embodiments may further comprise means located at the surface for detecting these pressure pulses in the annulus and, in accordance with one embodiment, also in the standpipe. An electrical signal commensurate with the modulation of the drilling fluid, as provided by the surface sensor or sensors, is conditioned to remove noise, i.e., signal variations lying outside of the energy spectrum of the expected signal, and thereafter preferably converted into digital format for computer processing. In a preferred embodiment the computer will be provided with information commensurate with other drilling parameters which may have an effect on the amplitude and/or phase of the signal or signals detected at the surface. These other drilling parameters may include, by way of example only, drilling fluid temperature which will have an effect on the velocity of sound transmission in the fluid. In one embodiment the conditioned standpipe and annulus pressure signals, after conditioning, are compared and the computer will analyze the results of the comparison to detect changes which cannot be explained by a variation in the drilling parameters. In another embodiment the computer will "look at" only the signal derived from the measurements taken on the drilling fluid flowing in the annulus and will compare such signals with their own stored near past history to look for unexpected variations. In yet another embodiment the sensed pressure signals, either before or in lieu of being converted into digital format, will be adjusted in amplitude and phase so that, under normal operating conditions, the signals commensurate with variations in annulus and standpipe pressure will null one another. Accordingly, only a difference in the conditioned signals greater than a preselected magnitude will be indicative of fluid influx from the formation being drilled into the annulus.

Viewed from a second aspect, the invention provides a method of monitoring a well drilling operation in which the sensed annulus pulses are used to determine fluid influx.

Some embodiments of the invention will now be described by way of example with reference to the accompanying drawings in which like reference numerals refer to like elements and in which:—

Figure 1 is a generalized schematic view of borehole drilling apparatus employing the present invention;

Figure 2 is a schematic view of a downhole energy source;

Figure 3 schematically represents a second embodiment of a downhole energy source;

Figure 4 is a functional block diagram of the surface located components of a borehole gas infusion detection system in accordance with one embodiment of the present invention,

Figure 5 is a waveform diagram depicting pressure signals sensed in accordance with the practice of the embodiment of Fig. 4 after the preconditioning thereof;

Figure 6 is a functional block diagram of the surface located components of a borehole gas infusion detection system in accordance with another embodiment of the present invention; and

Figure 7 is a functional block diagram of the surface located components of a borehole gas infusion detection system in accordance with yet another embodiment of the present invention.

Referring to Fig. 1, a drilling apparatus has a derrick 10 which supports a drill string or drill stem, indicated generally at 12, which terminates in a drill bit 14. As is well known in the art, the entire drill string may rotate, or the drill string may be maintained stationary and only the drill bit rotated. The drill string 12 is made up of a series of interconnected pipe segments with new segments being added as the depth of the well increases. The drill string is suspended from a moveable block 16 of a winch 18 and crown block 19, and the entire drill string of the disclosed apparatus is driven in rotation by a square kelly 20 which slideably passes through and is rotatably driven by the rotatable table 22 at the foot of the derrick. A motor assembly 24 is connected to both operate winch 18 and drive rotary table 22.

The lower part of the drill string may contain one or more segments 26 of larger diameter than the other segments of the drill string. As is well known in the art, these larger diameter segments may contain sensors and electronic circuitry for preprocessing signals provided by the sensors. Drill string segments 26 may also house power sources such as mud driven turbines which drive generators, the generators in turn supplying electrical energy for operating the sensing elements and any data processing circuitry. An example of a system in which a mud turbine, generator and sensor elements are included in a lower drill string segment may be seen

from US Patent No 3.693.428 to which reference is hereby made.

Drill cuttings produced by the operation of drill bit 14 are carried away by a mud stream rising up through the free annular space 28 between the drill string and the wall 30 of the well. That mud is delivered via a pipe 32 to a filtering and decanting system, schematically shown as tank 34. The filtered mud is then drawn up by a pump 36, provided with a pulsation absorber 38, and is delivered via line 40 under pressure to a revolving injector head 42 and thence to the interior of drill string 12 to be delivered to drill bit 14 and the mud turbine in drill string segment 26.

In a MWD system as illustrated in Fig. 3, the mud column in drill string 12 serves as the transmission medium for carrying signals of downhole drilling parameters to the surface. This signal transmission is accomplished by the well known technique of mud pulse generation whereby pressure pulses (which will be referred to sometimes as "primary pulses"), represented schematically at 11, are generated in the mud column in drill string 12 representative of parameters sensed downhole. The drilling parameters may be sensed in a sensor unit 44 in drill string segment 26, as shown in Fig. 1, which is located adjacent to the drill bit. The pressure pulses 11 established in the mud stream in drill string 12 are received at the surface by a pressure transducer 46 and the resulting electrical signals are subsequently transmitted to a signal receiving and processing device 48 which may record, display and/or perform computations on the signals to provide information of various conditions downhole.

Still referring to Fig. 3, the mud flowing down drill string 12 is caused to pass through a variable flow orifice 50 and is then delivered to drive a turbine 52. The turbine 52 is mechanically coupled to, and thus drives the rotor of, a generator 54 which provides electrical power for operating the sensors in the sensor unit 44. The information bearing output of sensor unit 44, usually in the form of an electrical signal, operates a valve driver 58, which in turn operates a plunger 56 which varies the size of variable orifice 50. Plunger 56 may be electrically or hydraulically operated. Variations in the size of orifice 50 create the pressure pulses 11 in the drilling mud stream and these pressure pulses are sensed at the surface by aforementioned transducer 46 to provide indications of various conditions which are monitored by the condition sensors in unit 44. The direction of drilling mud flow is indicated by arrows on Figs. 2 and 3. The pressure pulses 11 travel up the downwardly flowing column of drilling mud within drill string 12.

Sensor unit 44 will typically include means for converting the signals commensurate with the various parameters which are being monitored into binary form, and the thus encoded information is employed to control plunger 56. The sensor 46 at the surface will detect pressure pulses in the drilling mud stream and these pressure pulses will be commensurate with a binary code. In actual practice the binary code will be manifested by a series of information bearing mud pulses of two different durations with pulse amplitude typically being in the range of 2.10^5 to 25.10^5 Pa. The transmission of information to the surface via the modulated drilling mud stream will typically consist of the generation of a preamble followed by the serial transmission of the encoded signals commensurate with each of the borehole parameters being monitored.

As noted above, the drilling mud, after passing downwardly through segment 26 of the drill string, washes the drill bit 14 and then returns to the surface via the annulus 28 between the drill string and the wall 30 of the well. It has been discovered that the pressure pulse resulting from the movements imparted to plunger 56, also travel down the drill string and are reflected from the bottom of the well, although a greatly attenuated form, and result in pulses, indicated schematically at 55 in Fig. 3, in annulus 28 which may be sensed at the surface. Pulse 55 will sometimes be referred to as "secondary" or "reflected" pulses. To this end, as shown in Fig. 1, a second pressure transducer 60 is located at the surface and upstream, in the direction of returning mud flow, from the pipe 32. Typically the magnitude of the pressure pulses detected by transducer 60 are at least an order of magnitude less than the corresponding or companion pressure pulses detected by transducer 46. Nevertheless, through the use of appropriate filtering, these low magnitude pressure pulses in the annulus may be detected.

As noted above, the downhole energy source to generate the pulses 11 and the reflected pulses 55 may be the mud pulse valve of an existing MWD apparatus as depicted in Fig. 3. Alternatively, the downhole coherent energy source may, as indicated schematically in Fig. 2, comprise a wave generator which modulates the mud flow in the standpipe at a frequency in the sonic range. Thus, in Fig. 2, a flapper valve 56′ is located in an orifice defining member 50′ located in the drill string slightly upstream, in the direction of drilling fluid flow, from the drill bit 14 to generate primary pulses 11′ and secondary or reflected pulses 55′.

Returning to a discussion of Fig. 1, regardless of the nature of the downhole energy source, the drilling fluid flow will be modulated in the standpipe (i.e., the primary pulses) and the modulation, reflected from the bottom of the well, will also appear as pressure variations (i.e., the reflected pulses) in the annulus 28. At the surface the standpipe pressure variations (primary pulses) will be detected by transducer 46 to produce a P_S signal. Similarly the pressure variations (reflected pulses) in the annulus will be detected by transducer 60 and the resulting

P_R signal will be conditioned in circuitry which may include an amplifier 62 and filter 64.

The annulus pressure signal P_R, and in accordance with some embodiments of the invention also the standpipe pressure signals P_S, will be processed in the manner to be described in detail below. This signal processing may include comparing the signals in a comparator 66 followed by computer processing in a computer 68 or may comprise the direct inputting of the P_R signal, and possibly also the P_S signal, to computer 68. In order to enhance the accuracy of the computation in computer 68, one or more drilling parameters measured at the surface and/or one or more drilling parameters measured downhole may also be inputted to the computer 68. The computer 68 will operate in accordance with a gas detection program. The surface measurements which may be inputted to computer 68 include time, distance to the well bottom, standpipe pressure, the temperatures of the drilling fluid at the top of the standpipe and at the top of the annulus, the resistivity of the drilling fluid at the top of the standpipe and at the top of the annulus, the weight and/or density of the drilling fluid in the standpipe and annulus, the rate of rotation of the drill string, the pump strokes of the pump 36, the drilling fluid flow rate and the rate of penetration of the drill. The downhole measured information supplied to computer 68 may include temperature, pressure and resistivity measured in the vicinity of the drill bit. When analysis of the information inputted to computer 68 pursuant to the gas detection program indicates an abnormality, computer 68 will energize an alarm 70.

Referring now to Fig. 4, the analog pressure variation signal provided by standpipe pressure sensor 46 is delivered to a signal conditioning circuit 80 comprising amplifier 82 and filter 84. Signal conditioning circuit 80 removes noise outside the energy spectrum of the expected signal to produce a "clean" P_S signal. The P_S signal is converted, in an analog to digital converter 86, to a digital signal which is subsequently delivered to computer 68′. Similarly, the annulus analog signal provided by transducer 60 is conditioned, in circuit 88, by means of amplifier 62 and filter 64. The resulting P_R signal is converted to digital form, in an analog to digital converter 90, and then supplied to computer 68′.

Both digital signals are entered into computer 68′ at an appropriate rate, for example ten times the Nyquist rate, and the inputted data is stored chronologically in a memory 68″ for further processing. As noted above, drilling parameters such as pump strokes, mud flow rate, rate of penetration, mud temperature, etc. may also be entered into the computer to aid in the determination of gas infusion by factoring out the effects of the drilling operation on the digital signals. Mud temperature, of course, is of interest since the velocity of sound will vary with mud temperature and thus the phase relationships between the P_S and P_R signals will be a function of mud temperature and well depth. It is to be noted that, in addition to the analog signal conditioning circuits 80 and 88, further filtering using conventional digital filtering techniques may be used to reduce unwanted energy from outside sources and to take into account predictable effects such as pump strokes.

The fully conditioned signals are processed in computer 68′ under a correlation program. Particularly, the conditioned P_S and P_R signals are compared, the comparison consisting of the correlation between two functions $V_1(t)$ for P_S and $V_2(t)$ for P_R as follows:

$$R_{12}(\tau) \equiv \lim_{T \to \infty} \frac{1}{T} \int_{-\frac{T}{2}}^{+\frac{T}{2}} V_1(t) V_2(T + \tau)\, dt$$

where $R_{12}(\tau)$ refers to the correlation between the two signals V_1 and V_2.

The P_S and P_R signals have a similarity in frequency f(s) because they result from the operation of the same downhole energy source. The P_S and P_R signals also have a characteristic amplitude, respectively A(s) and A(a). The sensed annulus and standpipe pressure signals also have a fixed time relationship, i.e., a delay $\tau(d)$ which is dictated by the signal transmission medium, i.e., the drilling fluid. Through the correlation process, the characteristics of the P_S and P_R signals may be precisely determined on a continuous basis while drilling. When gas or other fluid enters the well bore the determined characteristics are upset by the presence of the intruding fluid. When one or more of the characteristics of the P_S and P_R signals are disturbed in excess of a predetermined limit, the computer 68′ will energize the alarm 70.

To elaborate on the above, the velocity of sound in a liquid such as drilling fluid is given by the following equation:

$$C^2 = \frac{K}{\rho}$$

Where: C is the velocity in cm/s
ρ is the fluid density of gm/cm^3
K is the bulk stiffness modulus (reciprocal of adiabatic compressibility) in dynes/cm^2.

The absorption of sound in a liquid is given by the following equation:

$$\gamma = \frac{16\pi^2 \mu_S}{3\rho C^3} f^2$$

Where: γ is the absorption coefficient (in 1/cm)
μ_S is the viscosity in poises
ρ is the density in gm/cm^3
C is the velocity of sound in cm/s
f is the frequency in Hz.

As noted above, formation fluid influx into the drilling fluid will affect the velocity of sound and the attenuation of sound in that fluid. For example, the specific gravity of oil, gas and salt water is less than that of a water based drilling mud and, accordingly, the density of a mixture of drilling mud and one of these other fluids will be lower than the density of the "pure" drilling mud.

Normally the pressure related signals P_S and P_R respectively provided by the standpipe transducer 46 and the annulus transducer 60, will be different in amplitude and phase because of a slight difference in transfer functions. These differences will be stored in memory 68′. When formation fluid flows into the annulus the transfer function, and thus the annulus pressure signal P_R will change. The transfer function for the standpipe fluid, and accordingly the signal P_S will remain unchanged. For example, assume that there is gas infusion from the formation into the annulus. The mixing of the gas influx with the drilling fluid will result in the density of the fluid in the annulus decreasing whereupon the amplitude of the P_R signal provided by transducer 60 will decrease. The fact that the P_S signal provided by transducer 46 has not changed in proportion to the change in P_R signal is evidence that there has been a fluid influx into the bore hole. There will also be a change in the phase angle relationship of P_S to P_R which results from the fact that the speed of sound in the fluid will change with the inverse of the square root of density. A change in phase difference or relative amplitude in excess of predetermined limits will result in computer 68′ generating a signal which energizes the alarm 70.

Fig. 5 is a representation of signals which would ideally be provided at the output of the signal conditioning circuits 80 and 88 as a result of the downhole modulation, for example by a "flapper" valve, of the drilling fluid at a frequency f(s). In actual practice the difference in amplitude of the standpipe and annulus signals is considerably greater than shown on Fig. 5 and this difference in characteristic amplitude is reduced through the use of the amplifiers in the signal conditioning circuits 80 and 88.

Fig. 6 may be considered to be a simplified hardware version of the embodiment of Fig. 4. In the Fig. 6 embodiment, the output signals from the signal conditioning circuits 80 and 88 are not converted to digital form. Rather, the P_S signal from conditioning circuit 80 is inverted in an inverting amplifier 92 and then delivered to a variable delay circuit 93 to delay the P_S signal so that it arrives at a summing amplifier 94 coincidently with the P_R signal. The ouput from delay 93 is applied as a first input to a summing amplifier 94. The P_R signal from conditioning circuit 88 is applied to a variable gain circuit 96. The gain of P_R is adjusted in circuit 96 such that the output of circuit 96, which functions as the second input to summing amplifier 94, will null the signal from inverter 92 and delay 93 when the correct amplitude and delay have been selected. Control of the gain of the P_R and delay of the P_S signals is under the control of a computer 98 connected to delay circuit 93 and gain circuit 96, the selected gain and delay being commensurate with the characteristic information of the system. The output from summing amplifier 94 is delivered to a detector 100, and detector 100 will provide a dc output voltage level commensurate with the average error signal appearing in the output of summing amplifier 94. Should either or both of the phase difference or amplitude ratio between the pressure signals in the standpipe and annulus vary by greater than a preselected minimum, the variation being detected by a detector circuit 100, the alarm 70 will be energized.

It is to be noted that the embodiment of Fig. 4, rather than applying a correlation program in computer 68, may operate with a summation and minimum detection program and thus be the digital equivalent of the Fig. 6 embodiment.

Fig. 7 comprises an embodiment of the present invention where only the annulus pressure P_R signal is employed with comparison being made between the instantaneous characteristics of P_R and the near term history (e.g., past 1/2 hour) thereof. The signal P_R will be delivered to a conditioning circuit 88 and the output of the signal conditioning circuit will be converted into a digital signal by ADC 90. The digital signal is delivered as an input to computer 68''' which operates under the control of an auto-correlation program stored in memory 68''''. In the Fig. 7 embodiment, when the characteristics of the P_R signal vary in a manner that cannot be explained by changes in drilling parameters such as mud flow rate or mud temperature, the alarm 70 will be energized. Thus, by way of example, if the amplitude of the P_R signal decreases in a manner which cannot be explained by the drilling conditions, attenuation caused by fluid influx from the formation into the bore hole will be the likely cause. Similarly, if there is an unexplained phase shift in the P_R signal compared to its own near term history, the cause will also likely be formation fluid influx into the bore hole.

In the context of MWD and the present invention, phase shift detection offers a special opportunity to monitor for gas infusion. A phase shift between P_S and P_R occurs when fluid enters annulus 28 because the transmission time for P_R changes because of change in density of the mud in the annulus. This phase shift occurs regardless of whether the signal P_R is of constant or variable frequency. However, there is also a special phase shift, that occurs if there is a frequency change in the generated signal. Thus, when going from a digital 1 to 0 or from 0 to 1 in P_S, there will be a phase shift present in P_S in drill string 12 and in P_R in annulus 28. A recognizable relationship exists between these special phase shifts in the absence of fluid influx into annulus 28. If fluid influx occurs, this relationship between these plates shifts will change, to indicate fluid influx. Thus, this phase relationship and departure therefrom is an additional signal characteristic usable in the present invention for signal comparison as described above.

CLAIMS

1. Apparatus for detection of fluid influx in a borehole in which a drill string is positioned, the drill string cooperating with the wall of the borehole to define an annulus, and in which drilling fluid is circulated from the surface through the interior of the drill string and into the annulus back to the surface, the apparatus for detection of fluid influx including means for generating a coherent energy signal at a downhole location and propagating said signal as a primary signal in the drilling fluid in said drill string and as a secondary signal in the drilling fluid in said annulus and means for detecting at least said secondary signal, and means for employing said detected signal in a comparison to determine fluid influx into the annulus.

2. An apparatus as claimed in Claim 1, further including means for detecting said primary signal and means for comparing at least one selected parameter of said primary signal with the same parameter of said secondary signal.

3. An apparatus as claimed in claim 2, wherein said selected parameter is the amplitude.

4. An apparatus as claimed in claim 2, wherein said selected parameter is the phase of said signals.

5. An apparatus as claimed in claim 3 or 4, wherein said means for detectiong said primary signal includes a first transducer for receiving said primary signal and generating a first output signal commensurate therewith, said means for detecting said secondary signal includes a second transducer for receiving said secondary signal and generating a second output signal commensurate therewith, and said comparison means includes computer means to receive and analyze said first and second signals in accordance with a fluid detection program.

6. An apparatus as claimed in claim 5, further including a first amplifier, a first filter and a first analog to digital converter between said first transducer and said computer, and a second amplifier, a second filter and a second analog to digital converter between said second transducer and said computer.

7. An apparatus as claimed in claim 3 or 4, wherein said means for detecting said primary signal includes a first transducer for receiving said primary signal and generating a first output signal commensurate therewith, said means for detecting said secondary signal includes a second transducer for receiving said secondary signal and generating a second output signal commensurate therewith, and said comparison means includes a comparator circuit and a minimum level detector connected to the output of said comparator circuit.

8. An apparatus as claimed in claim 7, further including a first amplifier, a first filter, converter means and variable delay means between said first transducer and said comparator circuit, and a second amplifier a second filter and variable gain means between said second transducer and said comparator circuit.

9. An apparatus as claimed in claim 8, further including a computer connected between said minimum level detector and both of said variable delay means and said variable gain means.

10. An apparatus as claimed in anyone of claims 1 to 9, wherein coherent energy signal generating means includes wave generator means in said drill string to modulate the flow of drilling fluid at a frequency in the sonic range.

11. An apparatus as claimed in any one of claims 1 to 10, wherein said coherent energy signal generating means includes pressure generating means for generating data bearing primary signals.

12. An apparatus as claimed in any one of claims 1 to 11, wherein said coherent energy signal generating means includes means in said drill string defining an orifice for flow of said drilling fluid, and wave generator means in said orifice defining means to generate pressure pulses in the drilling fluid at a frequency in the sonic range.

13. An apparatus as claimed in any one of claims 1 to 11, wherein said wave generator means is a flapper valve.

14. A method of monitoring a well drilling operation for the presence of fluid influx into the bore hole, the drilling operation comprising the use of a tubular drill pipe having a diameter which is less than the diameter of the borehole being formed, said monitoring being performed during the drilling of the borehole, the method comprising the steps of pumping drilling fluid down the interior of the drill pipe, the drilling mud exiting at or near the base of the drill pipe and returning to the surface via the generally annular space between the drill pipe and borehole wall, modulating the flow of drilling fluid in the drill pipe at a point near the bottom of the borehole, the modulating of the drilling fluid flow producing pressure pulses therein, sensing the pressure pulses in the drilling fluid returning to the surface via the said annular space, and employing the sensed annular space pressure pulses to determine fluid influx.

15. A method as claimed in claim 14, further comprising the step of monitoring the pressure pulses in the drill pipe at the surface, and wherein the step of employing the sensed annular space pressure pulses to determine fuid influx comprises comparing a parameter of the pressure pulses sensed in the annular space with the same parameter of the monitored drill pipe pressure pulses.

16. A method as claimed in claim 15, wherein the parameter is amplitude.

17. A method as claimed in claim 15, wherein the parameter is phase.

18. A method as claimed in any one of the claims 14 to 17, wherein the steps of modulating the flow of drilling fluid include operating pressure generating means for producing data bearing primary signals.

19. A method as claimed in claim 18, wherein the steps of modulating the flow of drilling fluid include directing said drilling fluid through an orifice, and generating a uniform wave of pressure pulses.

20. A method as claimed in claim 18, including the step of operating a flapper valve in said orifice to generate the wave of pressure pulses.

21. An apparatus for detection of fluid influx substantially as hereinbefore described and as illustrated in the accompanying drawings.

22. A method of monitoring a well drilling operation for the presence of fluid influx substantially as hereinbefore described and as illustrated in the accompanying drawings.

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